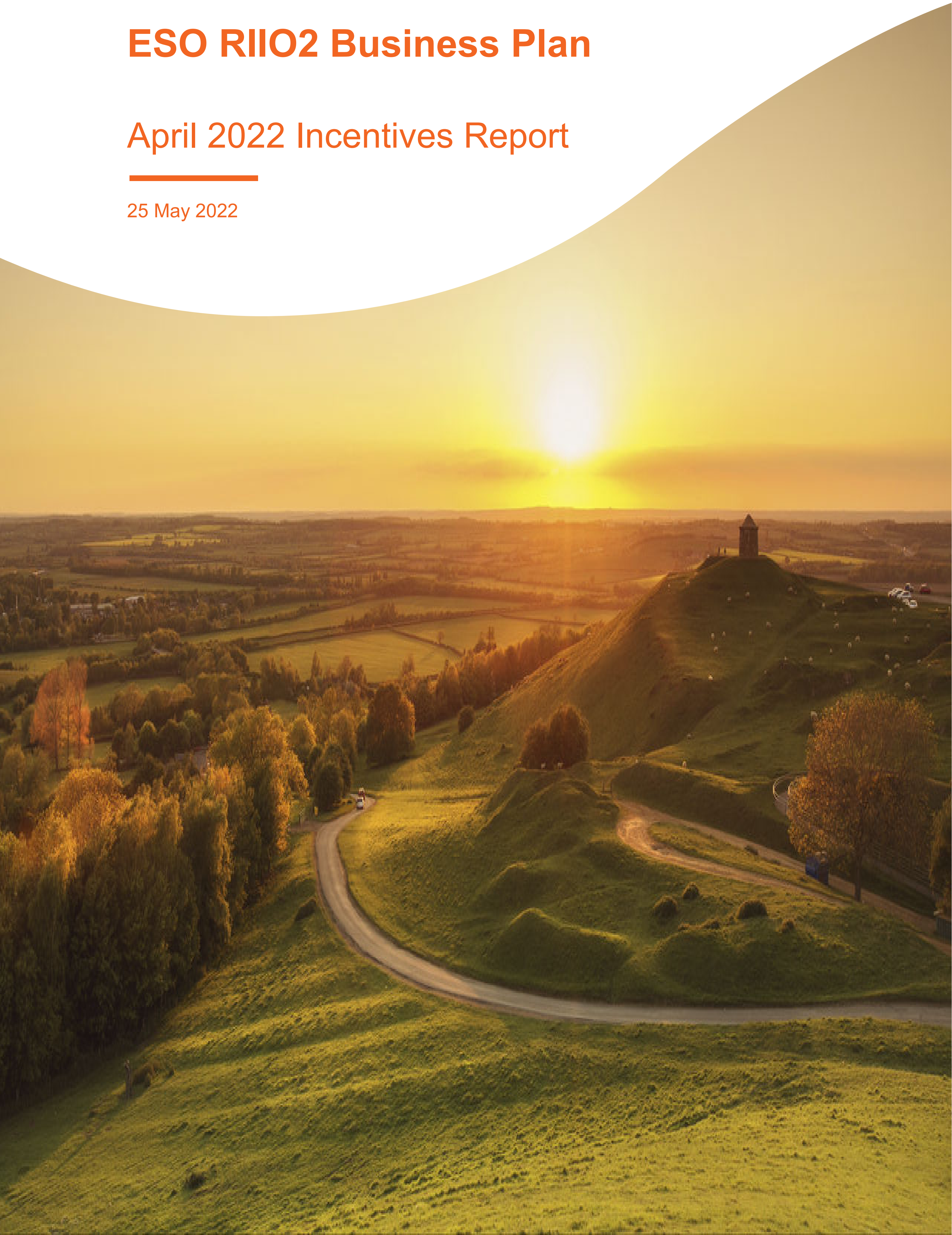
nationalgridESO

ESO RIIO2 Business Plan

April 2022 Incentives Report

25 May 2022



Contents

Introduction

The ESO's RIIO-2 Business Plan, submitted to Ofgem in December 2019, sets out our proposed activities, deliverables, and investments for 2021-26 to enable the transition to a flexible, net zero carbon energy system.

The ESO's Delivery Schedule sets out in more detail what the ESO will deliver, along with associated milestones and outputs, for the "Business Plan 1" period, which runs from 1 April 2021 to 31 March 2023.

Ofgem, as part of its Final Determinations for the RIIO-2 price control, set out that the ESO would be subject to an evaluative incentive framework, assessing our performance in delivering the Business Plan.

The ESO Reporting and Incentives (ESORI) guidance sets out the process and criteria for assessing the performance of the ESO, and the reporting requirements which form part of the incentive scheme. Every month, we report on a set of monthly performance measures; Performance Metrics (which have benchmarks) and Regularly Reported Evidence items (which do not have benchmarks). This report is published on the 17th working day of each month, covering the preceding month.

Every quarter, we report on a larger set of performance measures, and also provide an update on our progress against our Delivery Schedule in the RIIO-2 deliverables tracker.

Every six months, we produce a more detailed report covering all of the criteria used to assess our performance.

Please see our website for more information.

Summary

In April we have successfully delivered the following notable events and publications:

- The Balancing Programme is undertaking a strategic review of the systems used to support our balancing capability. We have been engaging extensively with industry so we can ensure that our plans and delivery roadmaps meet our RIIO-2 strategic objectives, minimise balancing costs, deliver consumer benefits and create a foundation for future market changes and reform.
- We published the 2021 Power Responsive Annual Report.
- Our new Dynamic Containment (DC) 4-day Forecast went live on the Data Portal.
- We shared a summary of our proposed product and service design for two new Reserve products: Negative Slow Reserve (NSR) and Positive Slow Reserve (PSR).
- We launched Dynamic Regulation and Dynamic Moderation. Both are pre-fault services, which form part of our new, faster-acting frequency response products alongside Dynamic Containment.
- We published our Five-Year view of Transmission Network Use of System (TNUoS) Tariffs for 2023/24 to 2027/28
- We invited industry participants to join focus groups about our Charging and Revenue process. This included TNUoS, Assistance for Areas with High Electricity Distribution Costs (AAHEDC), Balancing Services Use of System (BSUoS), and Connections Charging.

- We announced our innovation strategy, which has been developed in consultation with industry and is informed by the results of our Bridging the Gap work.
- Our latest Summer Outlook report was published, providing a view into the season ahead.
- We published the new, interactive, regional Future Energy Scenarios (FES) explainer which outlines our ambitions for modelling at a regional level to improve GB-wide forecasting.

The table below summarises our Metrics and Regularly Reported Evidence (RRE) performance for April 2022.

Table 1: Summary of Metrics

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£180m vs benchmark of £162m	
Metric 1B	**Demand Forecasting**	Forecasting error of 2.8% vs benchmark of 2.5%	
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.2% vs benchmark of 4.8%	
Metric 1D	**Short Notice Changes to Planned Outages**	5 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	
RRE 1E	**Transparency of Operational Decision Making**	99.7% of actions have reason groups allocated	N/A
RRE 1G	**Carbon intensity of ESO actions**	3.2gCO2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	1 instance where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	0 planned system outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 106%	N/A

Below expectations **Meeting expectations** **Exceeding expectations**

We welcome feedback on our performance reporting to box.soincentives.electricity@nationalgrideso.com

Gareth Davies
ESO Regulation Senior Manager

Role 1 Control Centre operations

Metric 1A Balancing cost management

April 2022 Performance

This metric measures our balancing costs based on a benchmark that has been calculated using the previous three years' costs and outturn wind generation. It assumes that the historical relationship between wind generation and constraint costs continues, recognising that there is a strong correlation between the two factors. Secondly, it assumes that non-constraint costs remain at a calculated historical baseline level. A more detailed explanation follows:

At the beginning of the year the non-adjusted balancing cost benchmark is calculated using the methodology outlined below. The final benchmark for each month is based on actual outturn wind, but an indicative view is provided in advance based on historic outturn wind.

i. Using a plot of the historic monthly constraints costs (£m) against historic monthly outturn wind (TWh) from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set to determine the monthly 'calculated benchmark constraints costs'.

ii. Using a plot of historic monthly total balancing costs (£m) against historic monthly constraint costs from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set, with the intercept value of that straight line used to determine the monthly 'calculated benchmark non-constraints costs'.

iii. An equation for the straight-line relationship between outturn wind and total balancing costs is then formed using the outputs of point (i.) and point (ii.).

iv. The historic 3-year average outturn wind for each calendar month is used as the input to the equation in point (iii). The output is 12 ex-ante, monthly non-adjusted balancing cost benchmark values. The sum of these monthly values is the initial 'non-adjusted annual balancing cost benchmark'. The purpose of this initial benchmark is illustrative as it will be adjusted each month throughout the year.

Total Balancing Costs *(£m)* = (Outturn Wind *(TWh)* x 12.16 *(£m/TWh)*) + 19.75 *(£m)* + 41.32 *(£m)*

A monthly ex-post adjustment of the balancing cost benchmark is made to account for the actual monthly outturn wind. This is done by following the process described in point (iv.) above but using the actual monthly outturn wind instead of the historic 3-year average outturn wind of the relevant calendar month. The annual balancing cost benchmark is then updated by replacing the historic value for the relevant month with this actual value.

ESO Operational Transparency Forum: The ESO hosts a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our National Control panel. Details of how to sign up and recordings of previous meetings are available here.

Updated benchmark for 2022-23 period: The benchmark for this metric has been updated provisionally for the period April 2022 to March 2023 in line with ESORI guidelines. These figures will be confirmed by Ofgem in due course.

Figure 1: Monthly balancing cost outturn versus benchmark (£m)

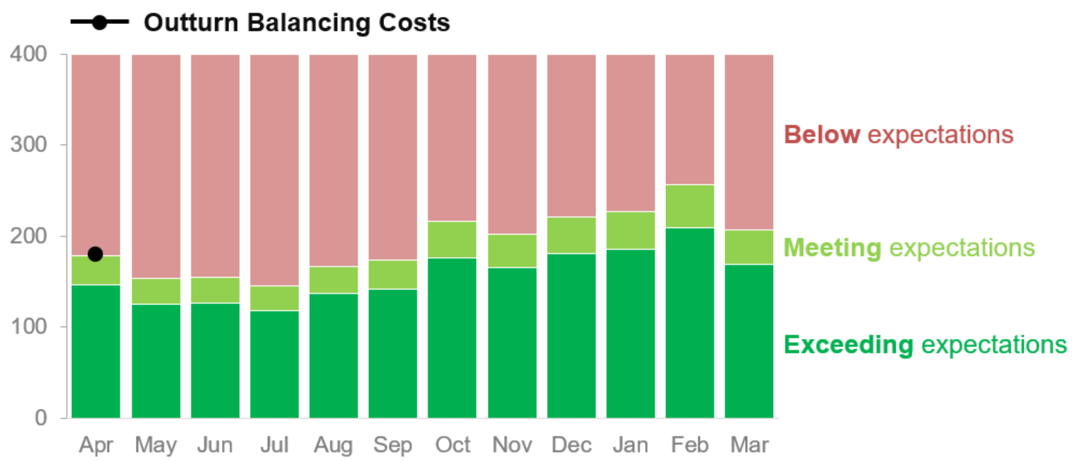


Table 2: Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	50.4	50.4	50.4	50.4	50.4	50.4	**50.4**
Indicative benchmark: constraint costs (B)	97.0	88.6	90.1	81.1	101.3	107.2	**97.0**
Indicative benchmark: total costs (C=A+B)	147.4	139.0	140.5	131.5	151.7	157.6	**147.4**
Outturn wind (TWh)	3.8						**3.8**
Ex-post benchmark: constraint costs (D)	112.3						**112.3**
Ex-post benchmark (A+D)	162.3						**162.3**
Outturn balancing costs[1]	180.4						**180.4**
Status	●						●

Performance benchmarks[2]

- **Exceeding expectations:** 10% lower than the balancing cost benchmark
- **Meeting expectations:** within ±10% of the balancing cost benchmark
- **Below expectations:** 10% higher than the balancing cost benchmark

Supporting information

April performance

The balancing costs for April 2022 were around £180m, which is a decrease of nearly £83m from the previous month, but more than 10% above the benchmark and therefore 'below expectations'. The outturn costs are closer to being in the 'meeting expectations' zone than in any month last year. This is because the benchmark for FY23 includes the elevated costs experienced in FY21 and also FY22.

Both constraint and non-constraint costs have decreased from the previous month, whilst remaining higher than last year.

Persisting high gas prices were the key factors responsible for continued high prices compared to last year for Operating Reserve, Fast Reserve, Response and Reactive, resulting in significantly higher non-constraint costs despite a substantial decrease in volume of related actions.

The significant constraint cost increase from last year is the result of continued very high wholesale prices. This in turn increases the cost of the Balancing Mechanism (BM) actions we are required to take in order to reduce generation behind constraints, and replace it with alternative generation. This is particularly the case at times of high wind and reduced boundary capability due to system outages.

[1] Please note that previous months' outturn balancing costs are updated every month with reconciled values

Breakdown of costs vs previous month

Balancing Costs variance (£m): April 2022 vs March 2022

		(a) Mar-22	(b) Apr-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-9.6	2.6	12.2	
	Operating Reserve	40.2	30.4	(9.8)	
	STOR	6.3	2.7	(3.6)	
	Negative Reserve	0.6	0.2	(0.3)	
	Fast Reserve	22.2	17.4	(4.8)	
	Response	25.2	23.4	(1.9)	
	Other Reserve	1.6	2.0	0.4	
	Reactive	20.0	21.2	1.2	
	Restoration	8.0	5.5	(2.5)	
	Minor Components	13.6	5.2	(8.4)	
Constraint Costs	Constraints - E&W	18.7	9.7	(8.9)	
	Constraints - Cheviot	4.2	8.6	4.4	
	Constraints - Scotland	54.4	23.1	(31.3)	
	Constraints - Ancillary	0.9	0.5	(0.4)	
	ROCOF	8.0	10.5	2.5	
	Constraints Sterilised HR	48.8	17.4	(31.3)	
Totals	Non-Constraint Costs - TOTAL	128.1	110.6	(17.5)	
	Constraint Costs - TOTAL	135.0	69.9	(65.1)	
	Total Balancing Costs	**263.1**	**180.4**	**(82.6)**	

As shown in the total rows above, the majority of this month's decrease in costs came in constraint costs, which account for around 80% of the overall decrease, with a reduction of over £65m. Non-constraints costs fell by nearly £18m.

Within the constraint category, the breakdown shows that Constraint-Cheviot and RoCoF were the only categories showing a cost increase from the previous month, with increases of £4.4m and £2.5m respectively.

Within non-constraints, Reactive and Other Reserve increased by a very small amount. Energy Imbalance costs increased from the negative level in the previous month, this cost is reflective of how balanced the market is, with a positive cost indicating that the market was short for the month as a whole.

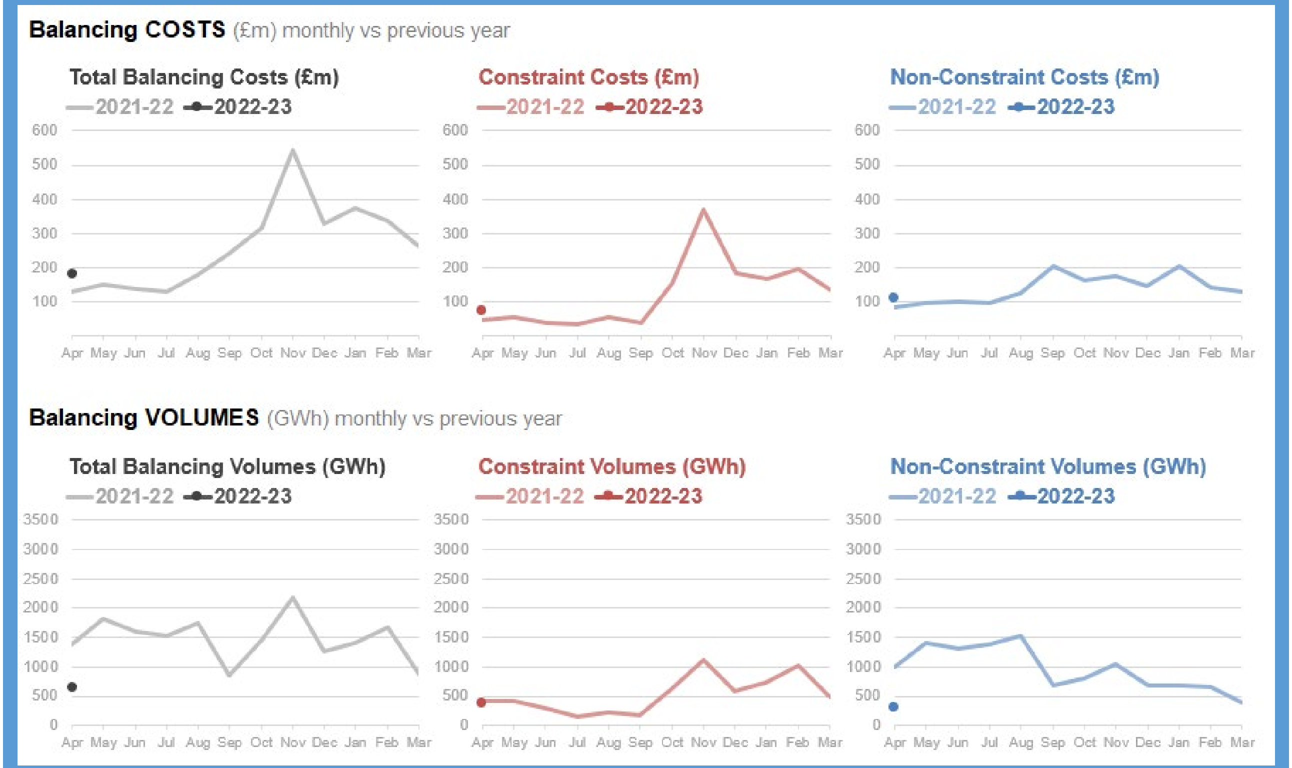
Overall, Operating Reserve, Constraint-Scotland and Constrained Sterilized Headroom were the categories with the largest decrease from March 2022.

The main drivers of the biggest cost variances this month are detailed below:

- **Constraint - Cheviot: £4.4m increase.** Despite a lower wind generation level compared to March, a change in the outage pattern and generation pattern moved the costs to the network boundary between England and Scotland, resulting in a cost increase compared to March for the Constraint-Cheviot category. The most expensive day for this category in April was Wednesday 6 April with a daily spend of nearly £5m.
- **RoCoF: £2.5m increase.** Lower inertia levels at times of high wind required a higher volume of BM actions to secure the system against the RoCoF risk. The spend has been mitigated through the application of the Frequency Risk and Control Report.
- **Constraint – Scotland: £31.3m decrease**. The cost decrease was in line with a lower wind generation level compared to March and with a change in the outage pattern that allocated costs to the Cheviot boundary. This resulted in fewer BM actions required to reduce generation in order to manage thermal Constraint in Scotland.
- **Operating Reserve: £9.8m decrease.** Healthier margins requiring less intervention to maintain reserve requirements were the key driver of the cost decrease for this category.

Constraint Costs vs Non-Constraint Costs

Restoration: Please note that the 2020-21 incentivised balancing cost figures did not include costs for restoration, but from April 2021 these are included. To enable a direct comparison, in the graphs below these restoration costs are included for both 2021-22 and 2022-23.



Constraint Costs

Compared with the same month of the previous year:

Constraint costs were £26m higher than in April 2021 due to

- The increased cost of actions to manage thermal constraints and network congestion during high wind periods. The volume of actions was lower than the previous year.

Compared with the previous month:

Constraint costs were £70m lower than in March due to:

- Reduced wind levels, resulting in an overall reduction in the volume of Balancing Mechanism actions to reduce generation required to manage thermal constraints compared to March.

Non-Constraint Costs

Compared with the same month last year:

Non-Constraint costs were £26m higher than in April 2021 due

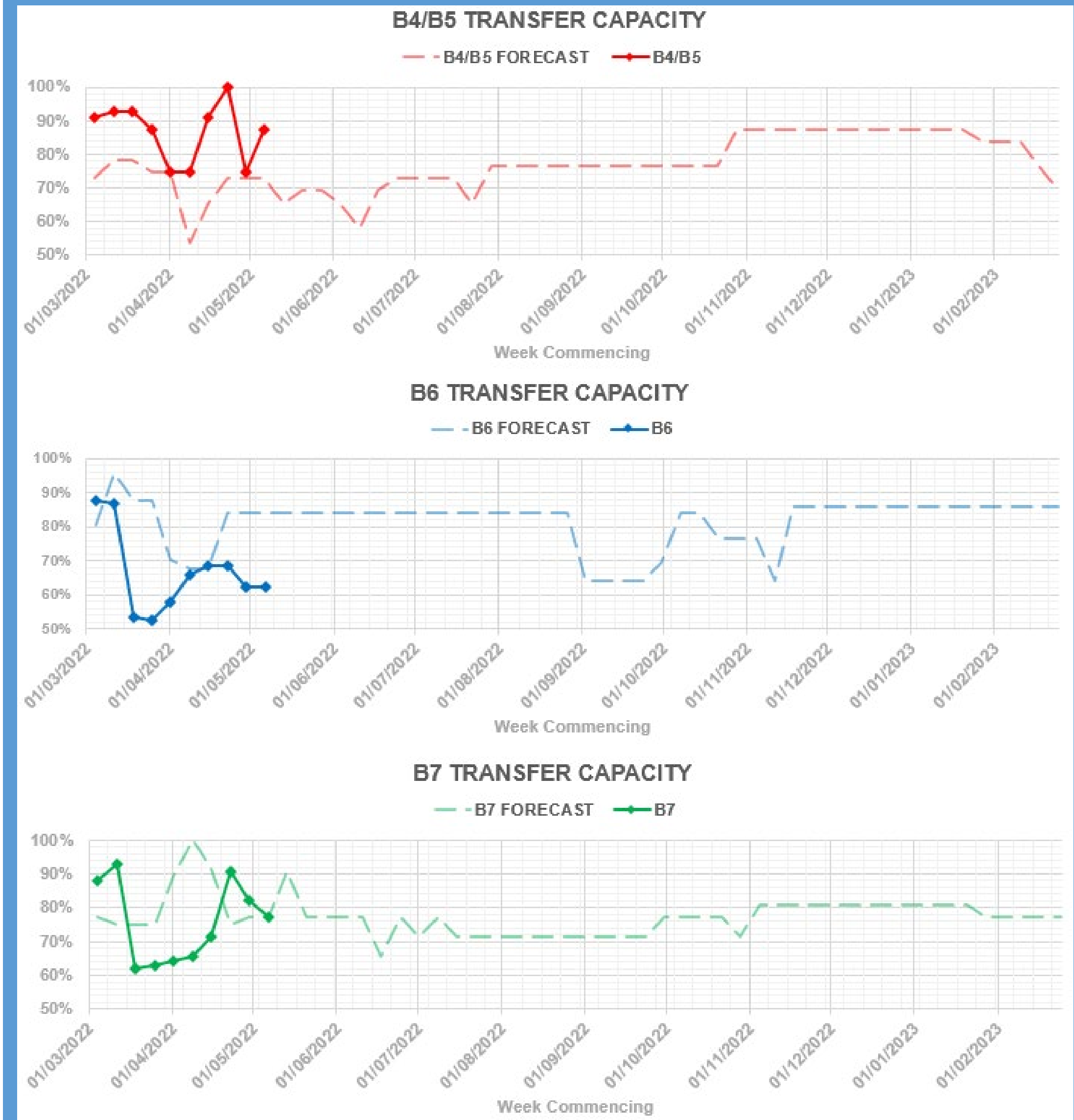
- The higher price of actions taken to manage the system. Particularly the price of offers in the BM which are higher due to increased wholesale costs. The volume of actions was lower than the previous year and this shows that it is the cost of the actions required rather than the volume which is driving the overall non-constraint cost.

Compared with the previous month:

Non-Constraint costs were £17.5m lower than in March due to:

- Overall lower volume of non-constraint related actions. Healthy margins with relatively stable wind output, along with our optimised procurement of services to alleviate multiple operability challenges with fewest actions, resulted in a lower volume than seen before on record.

Network availability 2022-23

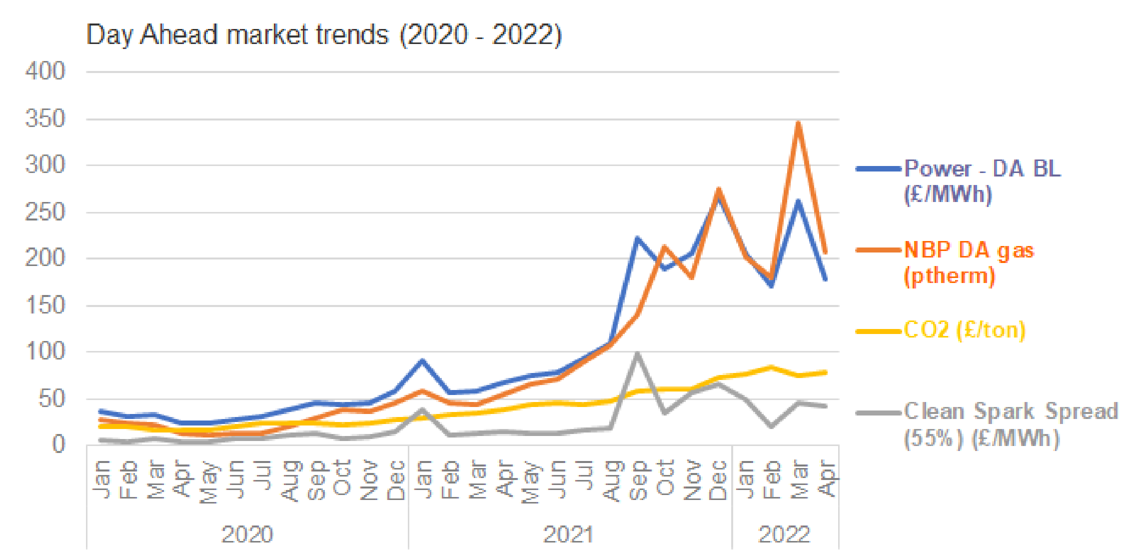


Boundary capacity has been above forecast for the B4/B5, internal Scotland boundaries for the majority of the month and at relatively high levels for most weeks. This is reflected in the lower Constraints – Scotland costs when compared to the previous month.

The B6 and B7 boundary capacities were significantly below the forecast and relatively constrained when compared to the 100% capacity. Despite the lower wind levels when compared to last month, the tighter constraint volume contributed to the increased Constraints – Cheviot costs for this month.

Please note that transfer capacity is discussed in more detail at each week's Operational Transparency Forum. Details of how to sign up, and recordings of previous meetings are available here.

Changes in energy balancing costs

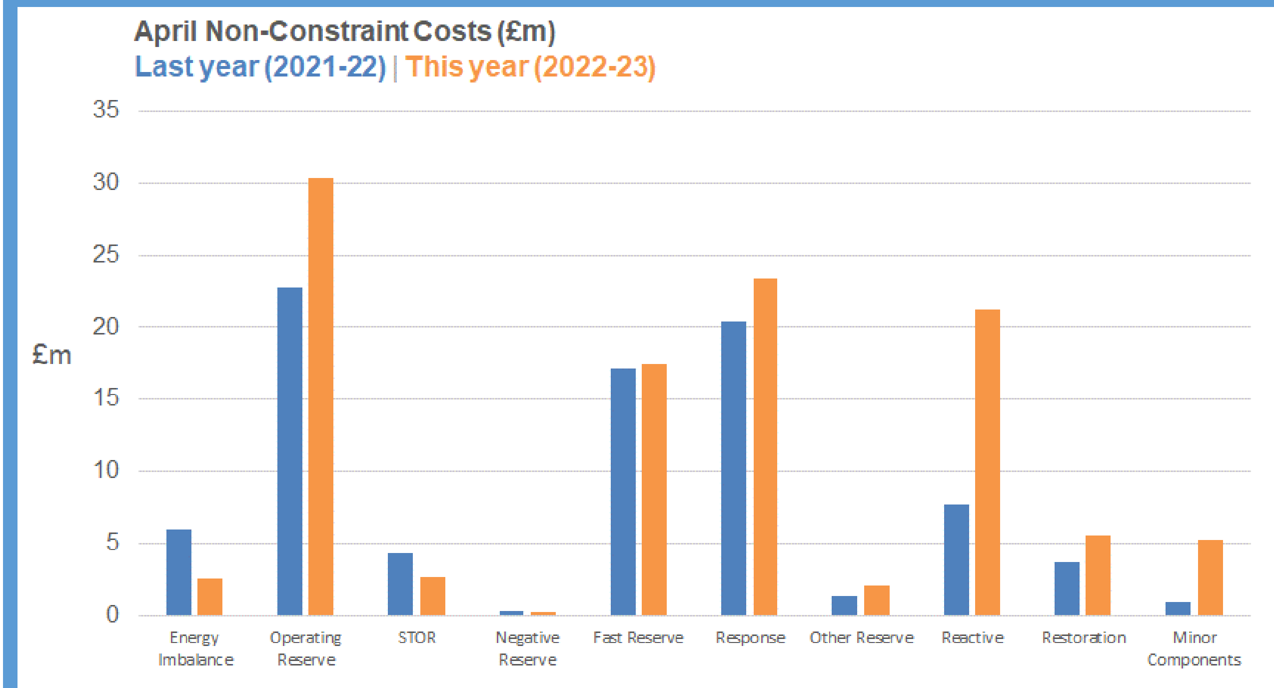


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power day ahead prices have fallen again in April but still remain significantly above the level of previous years. The day ahead gas prices have followed a similar trend and also remain very high in comparison with the previous year. Carbon prices continue the upward trend seen throughout 2021 and 2022 so far.

These continued higher prices impact on both the buy (offer) and sell (id) actions available to the ESO to manage our operability requirements. This demonstrates some of the external drivers of the underlying high prices available to ESO for balancing actions.

Cost trends vs seasonal norms



Comparing April 2022 non-constraint costs with those of April 2021 we can see that there has been a rise in all categories except STOR.

- **Operating Reserve** costs are £7.7m higher. This is mainly due to the high cost of BM actions driven by the continued high wholesale market prices along with scarcity pricing in periods of tight margin resulting in high offer prices submitted and taken for actions in the BM.

- **Reactive** costs are £13.5m higher. As the volume of actions taken is in line with seasonal norms, this is driven by the increased cost of the actions taken and is therefore related to the continued high wholesale market prices.
- **Response** costs are £3m higher. With the introduction of the Dynamic Containment service this continues to be higher spend than the previous year but offsets some costs in other categories.

Drivers for unexpected cost increases/decreases

Margin prices (the amount paid for a single MWh) have decreased since the previous month, due to overall healthier margins relieving the effect of scarcity pricing. However, the April margin price remains higher than the price recorded in April last year which reflects the increased cost of actions taken to make more generation available to meet our operational margin requirements.

Daily costs trends

In April 2022 there were high costs days where expensive action were needed to ensure all operability requirements were met. The monthly balancing costs outturned at £180.4m which is a decrease of £83m from the previous month.

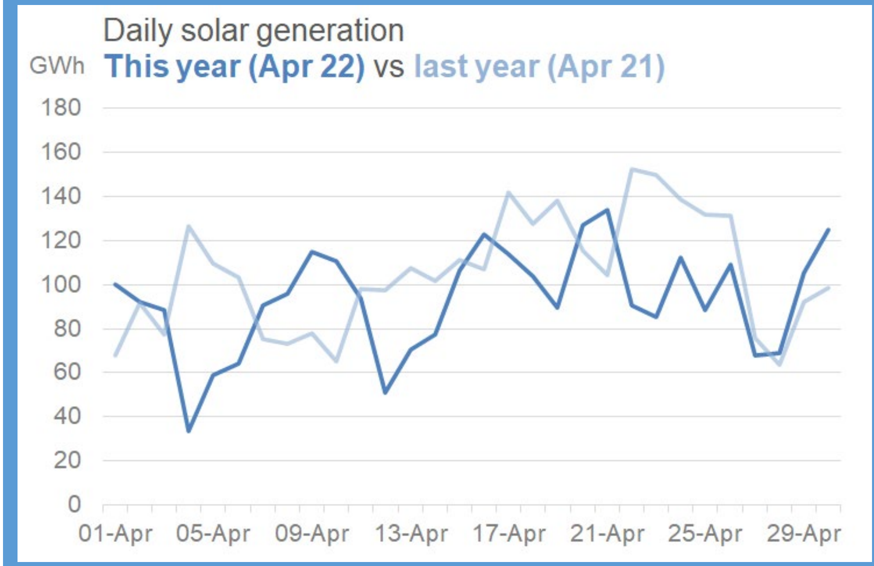
In April we counted 6 days on which the daily spend was around or above £10m, of which two days recorded a daily spend above £15m. The most expensive days were Monday 4 April and Thursday 7 April with outturns of £16.6m and £15.4m respectively. Other expensive days were Sunday 3 April, Wednesday 6 April, Saturday 23 April and Sunday 24 April, all of which had a daily outturn of around £10m. Windy weather requiring a large volume of BM actions to reduce generation to manage thermal constraints was the main driver behind these expensive days. When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids are required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance. The cost of the replacement energy is significantly higher than in previous years due to the ongoing high wholesale market prices.

High-cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated ESO control room actions.

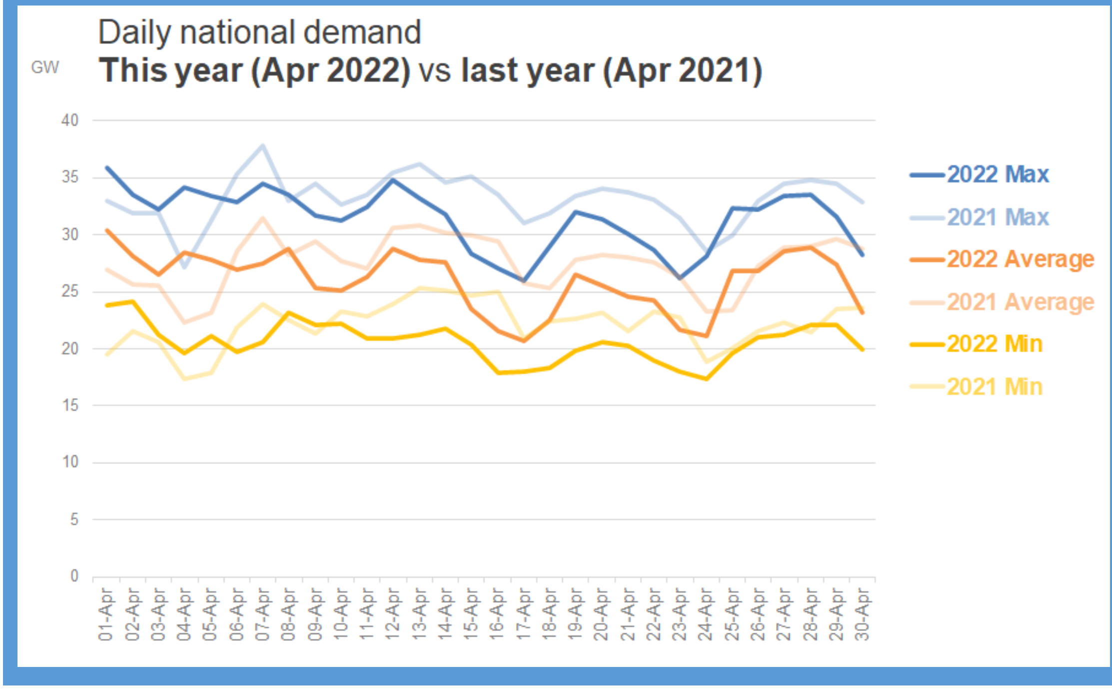
Significant events

There were no significant events during April.

Solar generation - comparison against last year



Outturn Demand vs 2020-21



Metric 1B Demand forecasting accuracy

April 2022 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast demand and outturn demand for each half hour period. The benchmarks are drawn from analysis of historical forecasting errors for the five years preceding the performance year.

If the Optional Downward Flexibility Management (ODFM) service is used, it will be accounted for in the data used to calculate performance. The ESO shall publish the volume of instructed ODFM.

A 5% improvement in historical 5-year average performance is required to exceed expectations, whilst coming within ±5% of that value is required to meet expectations.

Performance will be assessed against the annual benchmark of 2.1%, but monthly benchmarks are also provided as a guide. The ESO will report against these each month to provide transparency of its performance during the year.

Compared with last year's reporting, there are two differences in relation to metric 1B. The first one is that the performance is reported as the mean absolute percentage error (APE) rather than mean average error expressed in MW. The second difference is that the accuracy is measured for each Settlement Period, rather than each Cardinal Point.

Updated benchmark for 2022-23: The benchmark for this metric has been updated provisionally for the period April 2022 to March 23 in line with ESORI guidelines. These figures will be confirmed by Ofgem in due course.

Figure 2: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

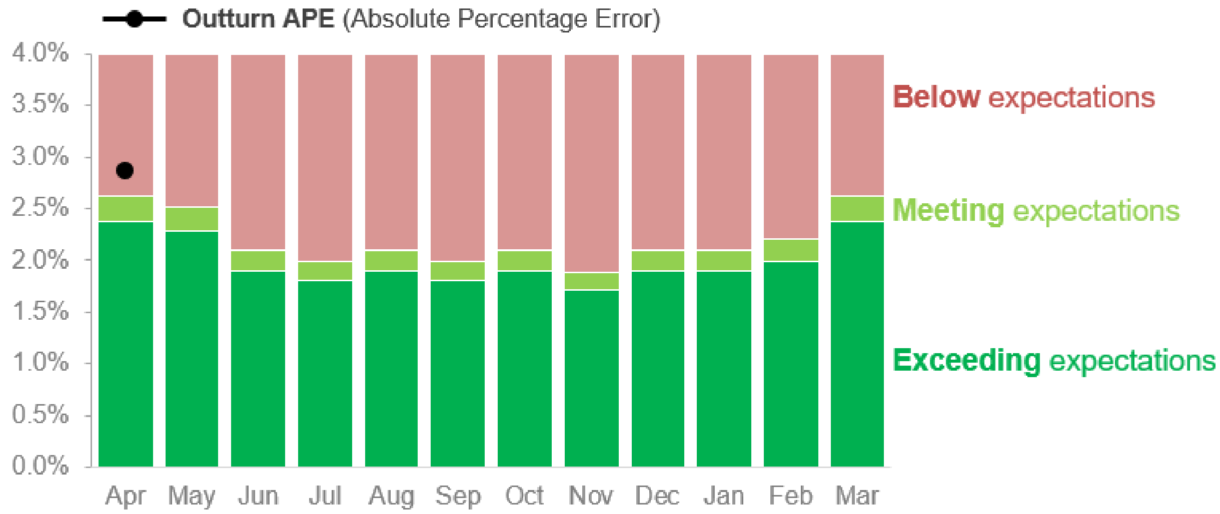


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Indicative benchmark (%)	2.5	2.4	2.0	1.9	2.0	1.9	2.0	1.8	2.0	2.0	2.1	2.5	**2.1**
APE (%)	**2.8**												
Status	●												

Performance benchmarks

- **Exceeding expectations:** <5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** >5% higher than 95% of average value for previous 5 years

Supporting information

For **April 2022**, our MAPE (mean absolute percentage error) was 2.8% compared to the benchmark of 2.5%, and therefore below expectations.

For demand forecasting in April there were two main factors at play that influenced accuracy.

Firstly, Easter brings a challenge to accurate forecasting because it limits the amount of historical data that can be used in demand prediction.

Secondly, there are still challenges in achieving accurate Solar PV forecasts. Solar PV forecasting error has a direct bearing on demand forecasting accuracy in the middle of the daytime. We are treating solar forecasting performance with high priority and investigating possible improvement. There is inherent, irreducible forecasting error with weather driven generation, which is outside of our control, i.e. weather data (radiation) data however there is a controllable element of the solar forecast, i.e. "model error" which we are going to work on in the next quarter.

Both these factors together caused the forecasting accuracy to miss the indicative monthly benchmark.

There were 0 occasions of missed or late publications in April.

Triads only take place between November and February, and therefore did not impact on forecasting performance during April.

Metric 1C Wind forecasting accuracy

April 2022 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast and outturn wind generation for each half hour period as a percentage of capacity for BM wind units only. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

A 5% improvement in historical 5-year average performance is required to exceed expectations, whilst coming within ±5% of that value is required to meet expectations.

Updated benchmark for 2022-23: The benchmark for this metric has been updated provisionally for the period April 2022 to March 23 in line with ESORI guidelines. These figures will be confirmed by Ofgem in due course.

Figure 3: BMU Wind Generation Forecast APE vs Indicative Benchmark (2022-23)

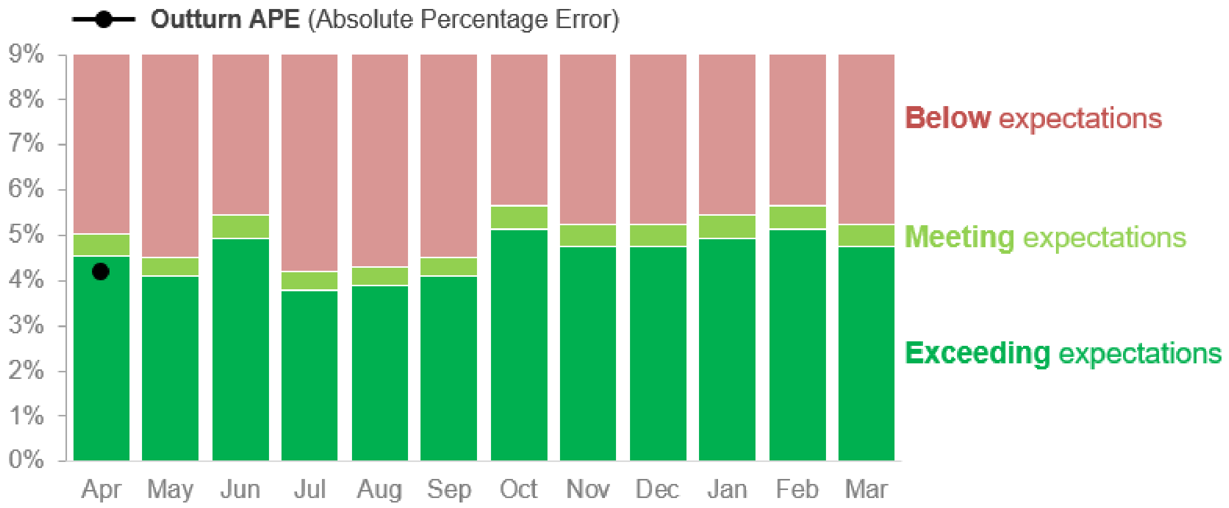


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
BMU Wind Generation Forecast Benchmark (%)	4.8	4.3	5.2	4.0	4.1	4.3	5.4	5.0	5.0	5.2	5.4	5.0	**4.8**
APE (%)	**4.2**												
Status	●												

Performance benchmarks

- **Exceeding expectations:** <5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** >5% higher than 95% of average value for previous 5 years

Supporting information

For **April 2022**, our MAPE (mean absolute percentage error) was 4.2% compared to the benchmark of 4.8% and therefore exceeded expectations.

Typically for April there have been periods where warmer spring weather has been apparent, interspersed with showery and heavy rainfall. April had some thunderstorm activity which indicates atmospheric instability. This atmospheric instability can cause localised turbulent wind conditions that are difficult to forecast accurately. Examples of this happened in the Thames Estuary on the 1st, The Humber region on the 2nd, East Anglia, Cumbria, Bristol and Southern Scotland on the 6th & 7th, scattered strikes across all of GB on the 8th, Cardiff and Central Wales on the 13th. Wind power forecasting is more challenging during the heavy downpours and blustery conditions that are accompany thunderstorms.

The intermittent market reference price for April had no negative prices.

There were 0 occasions of missed or late publications in April.

Triads only take place between November and February, and therefore did not impact on forecasting performance during April.

Metric 1D Short Notice Changes to Planned Outages

April 2022 Performance

This metric measures the number of short notice outages delayed by > 1 hour or cancelled, per 1000 outages, due to ESO process failure.

Figure 4: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

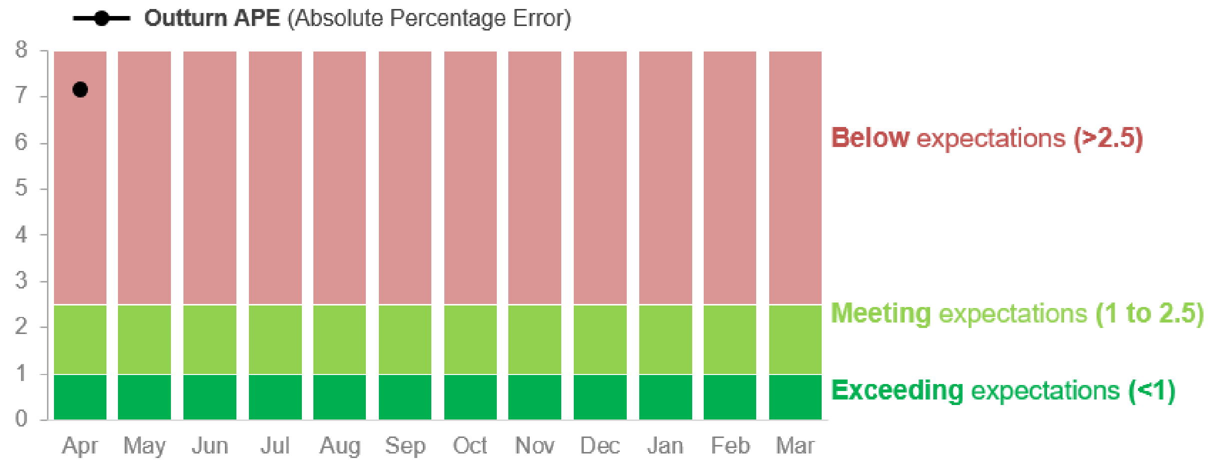


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700												700
Outages delayed/cancelled	5												5
Number of outages delayed or cancelled per 1000 outages	7.1												7.1
Status	●												●

Performance benchmarks

- **Exceeding expectations:** Fewer than 1 outage delayed or cancelled per 1000 outages
- **Meeting expectations:** 1-2.5 outages delayed or cancelled per 1000 outages
- **Below expectations:** More than 2.5 outages delayed or cancelled per 1000 outages

Supporting information

For April, the ESO has successfully released 700 outages and there have been 5 delays and 0 cancellations due to an ESO process failure. The number of cancellations or delays per 1000 outages is 7.14, which is above the target of less than 2.5 delays or cancellations per 1000 outages. Therefore, our performance is ‘below expectations’ this month. There are 4 events, leading to the 5 delays, as the second event caused 2 delays. We summarise these below:

1.	The first delay occurred due to a breakdown of communication between the ESO and a DNO relating to a trip test on a circuit where a Super Grid transformer (SGT) feeding DNO demand was connected. The outage experienced complications due to a limitation on the circuit breakers Delayed Auto Reclose (DAR) which restores the circuit and SGT following a transient fault. The ESO was unable to confirm agreement with the DNO planning engineers in advance of the outage. When the outage was requested by the TO, the DNO control room requested feedback from their planners before the outage could commence. As a result, the outage was cancelled and re-planned for the following day. An Operational learning Note (OLN) has been written to identify corrective measures and shared across the team.
2. & 3.	The second event relates to two aligned outages on a section of busbar within a 132kV substation and a Super Grid transformer (SGT). Part of the adjacent 275kV substation was on outage but this was not correctly captured in the outage planning database. This meant that it was not identified that for a given fault, some of the DNO demand would not be securable. Following this fault, the DNO demand would remain connected on a single SGT and the forecast demand was higher than the rating of the remaining SGT. Therefore, the ESO control room notified the DNO of the risk overnight, and the DNO was required to assess the impact if the contingency did occur. ESO agreed with the TO to re-plan these 132kV outages when works on the 275kV substation had finished later in the week, this mitigated the demand security concern. An Operational Learning Note (OLN) has been written to share corrective measures to mitigate a similar situation reoccurring ensuring all outages are correctly reflected in eNAMS.
4.	The third event was caused by a discrepancy between the planning tool used to simulate the outages and contingencies on the network (‘Off-line Transmission Analysis (OLTA) software’), and the real-time software used by the Control Room. Within planning timescales, the OLTA tool did not identify any problems for the contingencies simulated. However, the control room real-time simulation in advance of switching the circuit out identified a large voltage step change, which would have been exacerbated over the upcoming bank holiday where voltage management can be more challenging. The solution proposed by the ESO control room was to return a nearby substation to a solid configuration, instead of the current split configuration, to keep the volts within limits. However, this would require a DNO Supergrid Transformer (SGT) to be off-loaded overnight and a delay was experienced in obtaining the DNO agreement on this strategy. This is under investigation, with corrective actions to be identified.
5.	The final event was a delay to switching out an SGT feeding a 132kV DNO substation as the proposed substation running arrangement required the DNO substation to be operated solid. The 132kV substation had a fault level limitation where an SGT was required to be off-loaded for a short duration to configure the site. However, during the proposed period the selected SGT to be off-loaded could not be taken due to the high demands and subsequently, would have overloaded the remaining SGT for the switching time. Therefore, the ESO control room agreed with the DNO to switch the substation overnight when the demands would be lower and could be secured. An Operational learning Note is to be written.

RRE 1E Transparency of operational decision making

April 2022 Performance

This Regularly Reported Evidence (RRE) shows % balancing actions taken outside of the merit order in the Balancing Mechanism each month.

We publish the Dispatch Transparency dataset on our Data Portal every week on a Wednesday. This dataset details all the actions taken in the Balancing Mechanism (BM) for the previous week (Monday to Sunday). Categories and reason groups are allocated to each action to provide additional insight into why actions have been taken and ultimately derive the percentage of balancing actions taken outside of merit order in the BM.

Categories are applied to all actions where these are taken in merit order (Merit) or where an electrical parameter drives that requirement. Reason groups are identified for any remaining actions where applicable. Additional information on these categories and reason groups can be found on our Data Portal in the Dispatch Transparency Methodology.

Categories include: System, Geometry, Loss Risk, Unit Commitment, Response, Merit

Reason groups include: Frequency, Flexibility, Incomplete, Zonal Management

The aim of this evidence is to highlight the efficient dispatch currently taking place within the BM while providing significant insight as to why actions are taken in the BM. Understanding the reasons behind actions being taken out of pure economic order allows us to focus our development and improvement work to ensure we are always making the best decisions and communicating this effectively to our customers and stakeholders.

The Dispatch Transparency dataset, first published at the end of March 2021, has already sparked many conversations amongst market participants. It is anticipated that as we continue to publish this dataset, we will be able to provide additional insight into the actions taken in the Balancing Mechanism and help build trust as we become more transparent with our decision making.

Table 6: Percentage of balancing actions taken outside of merit order in the BM

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	92.3%										
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%										
Percentage of actions with no category applied or reason group identified	**0.3%**										

Supporting information

This month 92.3% of actions were taken in merit order or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis. During April 2022, we sent 31,860 BOAs (Bid Offer Acceptances) and of these, only 108 remain with no category or reason group identified, 0.03%.

RRE 1G Carbon intensity of ESO actions

April 2022 Performance

This RRE measures the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document. The monthly data can also be accessed on the Data Portal here. Note that the generation mix measured by RRE 1F and RRE 1G differs.

It is often the case that balancing actions taken by the ESO for operability reasons increase the carbon intensity of the generation mix. More information about the ESO's operability challenges is provided in the Operability Strategy Report.

Table 7: gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	3.2											

Supporting information

In April 2022, the average carbon intensity of balancing actions was 3.2 gCO2/kWh.

The time with the largest decrease in carbon intensity due to the ESO's actions was 15:30pm on 2nd April 2022 with a minimum of –18.4 gCO2/kWh. This was lower than March 2022's minimum value of -21.7 gCO2/kWh.

In April, the time with the highest carbon intensity increase was 06:30am on 24 April 2022 with a value of 39.7 gCO2/kWh. In comparison March 2022 had a maximum carbon intensity increase of 42.6 gCO2/kWh.

RRE 1I Security of Supply

April 2022 Performance

This Regularly Reported Evidence (RRE) shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz for more than 60 seconds, and where voltages are outside statutory limits. We will report instances where:

- The frequency is more than ± 0.3Hz away from 50 Hz for more than 60 seconds
- The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds.
- There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

For context, the Frequency Risk and Control Report defines the appropriate balance between cost and risk, and sets out tabulated risks of frequency deviation as below, where ‘f’ represents frequency:

Deviation (Hz)	**Duration**	**Likelihood**
f > 50.5	Any	1-in-1100 years
49.2 ≤ f < 49.5	up to 60 seconds	2 times per year
48.8 < f < 49.2	Any	1-in-22 years
47.75 < f ≤ 48.8	Any	1-in-270 years

At the end of the year, we will report on frequency deviations with respect to the above limits and communicate any plans for future changes to the methodology.

Table 8: Frequency and voltage excursions

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz)	0											
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	1											
Voltage Excursions defined as per Transmission Performance Report[3]	0											

Supporting information

There was one frequency excursion, and no voltage excursions in April 2022.

Frequency excursions details:

At 17:25 on Monday 18 April 2022, Sizewell B Units 1 and 2 tripped. This was a loss of 1260MW from the power station. Additionally, during the event there was a very small Distributed Energy Resources (DER) loss.

The ESO Control Room took immediate actions including instructions on BM and non-BM fast reserves, which resulted in the system frequency being recovered to within the lower operational limit of 49.8Hz within 5 minutes. Prior to the Sizewell B Units trip based on system conditions the ESO held enough Dynamic Response and Dynamic Containment – Low

[3] https://www.nationalgrideso.com/research-publications/transmission-performance-reports

responses and the post event analysis indicated responses performed adequately following the trip.

RRE 1J CNI Outages

April 2022 Performance

This Regularly Reported Evidence (RRE) shows the number and length of planned and unplanned outages to Critical National Infrastructure (CNI) IT systems.

The term 'outage' is defined as the total loss of a system, which means the entire operational system is unavailable to all internal and external users.

Table 9: Unplanned CNI System Outages (Number and length of each outage)

Unplanned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0											
Integrated Energy Management System (IEMS)	0											

Table 10: Planned CNI System Outages (Number and length of each outage)

Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0											
Integrated Energy Management System (IEMS)	0											

Supporting information

There were no outages, either planned or unplanned, encountered during April 2022.

Notable events during April

Balancing Capability Strategic Review launch

The Balancing Programme has been undertaking a strategic review of the systems used to support our balancing capability. We published an open letter[4], setting out our reasons for conducting the review and inviting stakeholders from across the industry to participate in it.

We have been hearing from industry stakeholders so we can ensure that our plans and delivery roadmaps:

- Meet our RIIO-2 strategic objectives
- Minimise balancing costs
- Deliver consumer benefits
- Create a foundation for future market changes and reform
- Engage with the industry

We have been receiving views and input from a wide range of stakeholders, to ensure that further investment will enable us to:

- Meet our net-zero carbon operability ambition
- Continue to remove barriers to entry for energy providers and encourage participation in the market
- Operate within increasingly challenging system conditions
- Shape an optimum transition path between our current and future balancing capability

Our engagement began in April and concludes at the end of May. Engagement has included a series of dedicated collaborative forum events, addressing different aspects of the review and seeking input and feedback from stakeholders. You can sign up to the final webinar on 27 May on our website.[5] We will be providing an update in our May performance report.

[4] https://www.nationalgrideso.com/document/248016/download

[5] https://www.nationalgrideso.com/industry-information/balancing-services/balancing-programme/strategic-capability-review

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

April 2022 Performance

This Regularly Reported Evidence (RRE) shows the accuracy of Balancing Services Use of System (BSUoS) forecasts used to set industry charges against the actual outturn charges.

Figure 5: Monthly BSUoS forecasting performance (Absolute Percentage Error)

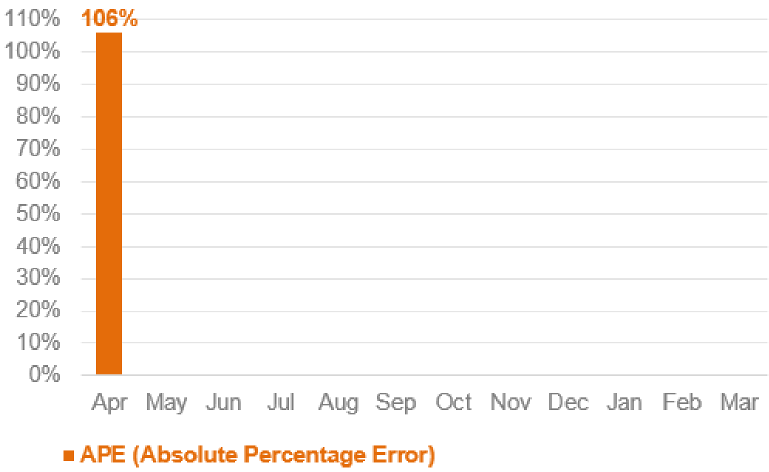


Table 11: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[6]

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	5.3											
Month-ahead forecast	11.0											
APE (Absolute Percentage Error)[7]	**106%**											

Supporting information

The outturn cost for April was 31% lower than the outturn for March. Wind load factors for March and April were very similar (approximately 28%), but the wholesale electricity prices were significantly lower in April (day ahead April price was £173/MWh compared to £250/MWh in March).

April outturn costs were significantly lower than the value produced in the March forecast. This is due to the elevated prices in the wholesale electricity forward curve available at the time. When the forecast was produced on March 9th, the month ahead wholesale price was approximately £350/MWh.

During April, we published our May 2022 BSUoS forecast and included a revised view of April. This was significantly lower at £8.49/MWh due to the significant reduction in wholesale electricity prices at the time of forecast production.

[7] Monthly APE% figures may change with updated settlements data at the end of each month. Therefore, subsequent settlement runs may impact the end of year outturn.

Notable events during April

Power responsive annual report

In April we published the 2021 Power Responsive Annual Report[8], which reflects on policy, regulatory and market developments over the past year as well as trends in demand side flexibility participation. This report is designed to help stakeholders navigate industry change and complexity and support the continued development of demand side participation in flexibility markets.

Dynamic Containment (DC) 4-day Forecast

Our new Dynamic Containment (DC) 4-day Forecast went live on the data portal in April. This gives providers a more accurate, closer to real-time view. The dataset contains forecasts of our Dynamic Containment Low and High requirements for the next 4-days. The methodology uses forecasted demand, inertia, and response volumes as well as a view of the largest losses on the system to estimate the DC requirements.

Reserve products

We shared a summary[9] of our proposed product and service design for two new Reserve products. The Reserve Reform project is developing a suite of new products to ensure safe and secure operation of the network in a zero-carbon world. Our aim is to introduce standardised products which are transparent, fair and competitive for all technology types, ultimately promoting market depth and reducing costs to the end consumer. This document seeks views on key elements of product and service design for the first two new products: Negative Slow Reserve (NSR) and Positive Slow Reserve (PSR). In parallel, we are working on the design for other Reserve products and will publish a similar summary of proposed service design as soon as possible to seek feedback from industry in the same way that we are for Slow Reserve. Through this latest engagement, we want to showcase our thinking behind the Slow Reserve products and seek input on some elements still being defined. We will be engaging with industry participants via a series of events where we will discuss our proposals in more detail.

Launched Dynamic Regulation and Dynamic Moderation

In April we launched our Dynamic Regulation (DR), the latest service in our suite of new frequency response services. The first DR auction took place on Friday 08 April and its results are now available on the ESO Data Portal[10]. DR is a pre-fault service, which forms part of our new faster acting frequency response products alongside Dynamic Containment. It is designed to slowly correct continuous but small deviations in frequency with the aim to continually regulate frequency around the target of 50Hz.

Dynamic Moderation (DM) is also a pre-fault frequency response service that we've designed to rapidly deliver with the aim of assisting the ESO to keep frequency within operational limits. This went live on the EPEX auction platform on Thursday 21 April. Providers are now able to access the platform and had 14 days to submit their bids ahead of the first auction which was on Friday 06 May.

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8 https://everoze.maglr.com/annual-report-2021

9 https://www.nationalgrideso.com/document/249031/download

10 https://data.nationalgrideso.com/ancillary-services/dynamic-containment-data

Five-Year View of Transmission Network Use of System (TNUoS) Tariffs

Our Five-Year View of TNUoS Tariffs for 2023/24 to 2027/28 was published in April[11]. TNUoS charges are designed to recover the cost of installing and maintaining the transmission system in England, Wales, Scotland and offshore. They are applicable to transmission connected generators and suppliers for use of the transmission networks.

Transmission Demand Residual (TDR) banded charges methodology will apply from charging year 2023/24 (as per Ofgem's recent decision on CMP343) and have been included in our initial tariffs for 2023/24 onwards. The total TNUoS revenue to be collected is forecast to be £3,947m for 2023/24 (an increase of £353m from the 2022/23 financial year), rising to £4,405m in 2027/28. OFTO revenue is forecast to increase steadily in the next five years whilst onshore TOs revenues also increase (by a comparatively much smaller amount) under their RIIO-2 business plan. The 2023/24 revenue forecast will be updated through the year and finalised by January Final Tariffs, based on onshore and offshore TOs' submissions and other relevant information. We then held a webinar on Thursday 14 April to assist industry in understanding its key findings and answer questions about the publication.

Charging and Revenue process webinars

We invited industry participants to join focus groups about our Charging and Revenue process. We held a workshop on TNUoS and Assistance for Areas with High Electricity Distribution Costs (AAHEDC) on Tuesday 26 April and a workshop for Balancing Services Use of System (BSUoS) on Thursday 28 April. We also held one for Connections Charging on Friday 29 April. This was well received by attendees.

[11] https://www.nationalgrideso.com/document/248611/download

Role 3 System insight, planning and network development

Please note there are no monthly or quarterly metrics or RREs for Role 3.

Notable events during April

Innovation strategy

We announced our innovation strategy[12] in April, this has been developed in consultation with industry and informed by the results of our Bridging the Gap work. It sets out how we need to innovate in 2022/2023, our strategic priorities, the role innovation is playing at the heart of GB's transition to zero carbon, and where to focus our efforts to set us on the right path for 2025 and beyond.

Summer Outlook Report

We have published our latest Summer Outlook report[13] which provides a view into the season ahead. This year, we've undertaken extra analysis to address the global energy crisis. We continue to monitor its impact on GB energy prices and system operability and will provide further updates through our Operational Transparency Forum as required. We have taken a number of measures to reduce costs to consumers, these measures include the development of pathfinder projects, new pre-fault frequency services and the delivery and implementation of this year's Frequency Risk and Control Report. Upward margins are traditionally less of a concern during summer due to lower peak demands than in winter. However, due to the events in Ukraine, we have carried out additional analysis assessing a range of possible interconnector scenarios. We continue to have the right tools and services available to manage system operability during the summer, such as our stability services and Dynamic Containment.

Regional Future Energy Scenarios (FES)

Our new, interactive regional Future Energy Scenarios (FES) explainer[14], which outlines our ambitions for modelling at a regional level to improve GB-wide forecasting, was published in April. Regionalisation will enhance FES to accelerate GB towards net zero by applying a whole system lens, offering greater granularity, broader engagement, and more regional insights. Currently we create top down scenarios from individual components of demand and supply. We then spilt this into regions for network development purposes. Regional scenarios mean we will work with the network companies and other stakeholders to adopt a more people centred approach on a regional basis.

We held a regional FES webinar on Thursday 19 May to answer any questions from industry participants.

[12] https://reports.nationalgrideso.com/innovationstrategy/
[13] https://www.nationalgrideso.com/document/248821/download
[14] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/regionalisation-fes/explainer